# Competition in the Dutch electricity wholesale market

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# Competition in the Dutch Electricity Market: An Empirical Analysis over 2006–2011

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**ABSTRACT**

We assess the development of competition in the Dutch electricity wholesale market over 2006–2011. In this period domestic generation capacity, both centralized and decentralized, as well as the cross-border transmission capacity increased. Using hourly plant-level data of centralized units and engineering-costs estimates, we estimate the weighted average Lerner index. During super peak hours, the annual average value of this index decreased from 0.23 in 2006 to 0.03 in 2011, indicating more competition. We find indications that the increase in competition can be attributed to the extension of cross-border connections, a higher price elasticity of net demand and more Bertrand-like competition. Enhancing the role of decentralized generation as well as fostering integration of markets seem to be effective measures to promote competition.

**Keywords:** Electricity market, Competition, Regulation, Time-series analysis

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## 1. INTRODUCTION

Electricity markets are widely seen as vulnerable to competition problems because of their characteristics: highly inelastic and volatile demand, entry barriers, economies of scale, transmission constraints, frequent market interaction among suppliers on spot as well as forward markets and the impossibility to store electricity while demand needs to be permanently equal to supply (Holmberg and Newbery, 2010). These factors not only cause these markets to be tight from time to time, but they also complicate the development of competition. In this respect, the fundamental problem is that firms can have dominant positions which are difficult to change (Green, 2007). Firms defend these positions by means of mergers and acquisitions (Bergman, 2005; Jamasb and Pollitt, 2005; Percebois, 2008). Hence, one can doubt to what extent competition in this market can be really achieved (Twomey, Green, Neuhoff and Newbery, 2005). Indications of abuse of market power in US electricity wholesale markets were found by, amongst others, Sheffrin (2001), Borenstein, Bushnell and Wolak (2002), Joskow and Kahn (2002) and Mansur (2008). Wolak (2007) concluded that the benefits of introducing competition are small compared to the benefits achieved in other network industries because of the exercise of unilateral market power. For several European power markets, London Economics (2007) found that electricity prices were related to the pivotal position of electricity producers. For the German electricity market, Müsgens (2006) estimated that prices were on average about 50% above competitive levels in the period 2001–2003, while in 2011 the German

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competition authority concluded that the level of competition in the German wholesale market is still unsatisfactory (Bundeskartellamt, 2011).

Some authors, however, find that wholesale markets have been fairly competitive. Green (2011) concluded for the British market that the evidence for strategic behavior by the power companies is weak and that the supply decisions are mainly set in a competitive manner. For the Nordic countries, Bergman (2005) found that through market integration and the introduction of forward markets, "workable" competition has been realized. Joskow (2006, p. 10) even stated that in the Northeast of the United States market-power mitigation measures have been too successful making it impossible for prices to rise to competitive levels when demand is high, resulting in aggregated profits below the levels needed to recoup fixed costs. Puller (2007) found that pricing behavior in the Californian spot markets during 1998–2000 was consistent with Cournot competition, where the large variation in price-cost margins mainly resulted from changes in the residual demand elasticity. So, despite the common view that market power is a fundamental characteristic of electricity markets, the degree to which prices are actually distorted appears to be an empirical issue.

In this paper, we test whether the intensity of competition in the Dutch wholesale electricity market changed over the period 2006–2011. A number of years ago, serious concerns existed about the limited liquidity of this market and the ability of the incumbents to exert market power during peak hours (Van Damme, 2005). Since then, the Dutch market has become more integrated with the neighboring countries through both physical and virtual extensions of cross-border capacity. We test whether this has intensified competition.

We estimate the weighted average Lerner index for each hour in 2006–2011. This index is defined as the day-ahead price minus the marginal costs per firm over this price while the weighing is based on the share of each firm in the total level of generation. The marginal costs per firm are based on actual plant-level data, using engineering-costs estimates. In addition, we assess the contributions of a number of explanatory variables to this Lerner index, in particular the HHI based on production by flexible generation plants and import, the level of domestic demand corrected for the supply from decentralized generation plants and a number of indicators for the influence from the German market. We find that, during super peak hours (defined as 10am to 7pm during working days), the annual average value of this index declined from 0.23 in 2006 to 0.03 in 2011, indicating more competition. Together with the increase in competition and the decrease in net demand, the annual operational profit per plant significantly reduced. We find indications that the increase in competition can be attributed to the extension of cross-border connections, a higher price elasticity of demand and more Bertrand-like competition.

This paper differs from previous studies as it focuses on the development of competition over a relatively long period of time by using high-frequency data on plant level for a specific market, i.e. the Dutch market, where competitive conditions have changed substantially over the past few years. Our conclusions contribute to the debate about the efficiency of additional measures to improve competition in the electricity wholesale markets. From the Dutch experience, we learn that enhancing the role of decentralized generation as well as fostering integration of markets can be effective measures to promote competition in the electricity market.

The remaining of this paper is structured as follows. Section 2 presents the theoretical underpinning of the analysis. Section 3 describes the main characteristics of the Dutch electricity market. Section 4 presents the empirical model. The data are described in Section 5, while the results are presented in Section 6. Section 7 concludes.

## 2. MODELLING MARKET POWER

In studies that model market power in the electricity wholesale market, Cournot models are widely used (e.g. Borenstein et al., 2002; Joskow and Kahn, 2002; Müsgens, 2006; Puller, 2007). Although some papers find that prices are consistent with the Cournot equilibrium (e.g. Puller, 2007), the results vary and standard Cournot models typically show prices that are too high while output is too low for realistic values of the price elasticity (Willems, Rumiantseva and Weigt, 2009). In contrast, Supply Function Equilibrium (SFE) models are considered to be more realistic for electricity markets. With these models, suppliers bid in supply functions for each generator instead of single quantities for a certain price. Although they typically present more realistic results compared to the Cournot models, they require extensive calculations with strong assumptions, while often generating multiple equilibria and giving unstable solutions. Comparing the results from Cournot models and SFE models, Willems et al. (2009) find that Cournot models can be easily calibrated with forward contracts to obtain realistic results. They therefore suggest using Cournot models for short-term analysis and SFE models for long-term analysis, as the latter are less sensitive to calibration and therefore particularly suitable to predict long-term effects.

As our focus lies on the short-term, using hourly data, we assume Cournot competition in which market power is related to the degree of concentration. In a Cournot market, the relationship between competition and market structure can be described as $LI = HHI/\varepsilon$, where $LI$ is the weighted average Lerner index, $HHI$ is the Herfindahl-Hirschman index and $\varepsilon$ the (absolute) elasticity of market demand with respect to price (Motta, 2004). The Lerner index is broadly used as a measure for market power (Elzinga and Mills, 2011). The Lerner index measures the intensity of competition by the degree to which price exceeds marginal costs: $LI_i = (p - mc_i)/p$, where $mc_i$ is the marginal costs of firm $i$ and $p$ is the market price.

The relationship between the weighted average Lerner index and HHI is, however, not straightforward (Borenstein, Bushnell and Knittel, 1999; Willems et al., 2009). This holds in particular for electricity markets where market power strongly depends on the magnitude of demand, given the non-storability of electricity and the short-term inflexibility of supply. To control for this, one should measure the HHI on the basis of flexible, not yet contracted production (Holmberg et al., 2010). If the HHI is measured on flexible production, its impact on the Lerner index is directly related to the price elasticity of demand. The importance of the latter for assessing competition is confirmed by Puller (2007) as well as Giabardo, Zugno, Pinson and Madsen (2010), who both found that an increase in the price elasticity of demand decreases the possibility of power firms to exploit their market power.

Competition in electricity markets is also related to the overall level of demand. The demand level may influence competition through a number of mechanisms. The Cournot model is in particular valid at higher demand levels when technical constraints must be considered by firms, while at lower demand levels competition is more Bertrand-like resulting in more competitive prices (Willems et al., 2009). Another mechanism by which the demand level affects the Lerner index is related to the fact that the marginal firm can raise its price up to the level of the marginal costs of the next plant in the merit order (Borenstein et al., 1999). As supply curves often become steeper at higher load levels, including the demand level in the analysis may capture this effect. Note that the steepness of the merit order may change over time, affecting the degree the electricity price is related to the marginal costs. The flatter the merit order, the smaller the distance between the price which firms require and their own marginal costs, suggesting a more Bertrand-like competition. In addition, the more capacity is used, the weaker the ability of the remaining capacity to respond to further increases in demand, resulting in prices (strongly) exceeding system marginal costs. A positive impact of demand on prices in the electricity wholesale market was already shown by Green and Newbery (1992) for the UK markets. We therefore expect that the Lerner index is positively related to the level of demand.

For the market power of the incumbent suppliers, the residual demand in particular is relevant (Davis and Garcés, 2010). The residual demand captures both the total demand and the responses by fringe suppliers, i.e. suppliers which supply is fully determined by their marginal costs in relation to the actual market price. Hence, the supply function of the fringe suppliers can be seen as negative demand from the perspective of the incumbents.

An alternative way to account for the influence of both industry structure and the level of demand is to use an indicator for pivotality (Bergman, 2005; Twomey, et al., 2005; Mulder and Schoonbeek, 2013). The generally used measure for pivotality is the Residual Supply Index (RSI), which is the ratio between the capacity of the other producers and the total demand. In case of Cournot competition, the Lerner index is theoretically negatively related to the RSI, while the size of this relationship depends on the price elasticity of residual demand (Newbery, 2008; Swinand et al., 2010). Newbery (2008) proves that this equation holds in a symmetric n-firm oligopoly with contracting and where each firm has the same capacity as well as identical cost functions. When firms have different capacities and/or different costs functions, however, the relationship is less straightforward, making it complicated to interpret the implication of changes in the RSI for competition. We, therefore, choose to relate the Lerner index to the HHI of not-yet-committed production and the level of net demand, which is the total demand excluding the part which is served by decentralized generation.

## 3. THE DUTCH ELECTRICITY MARKET

The Dutch wholesale market for electricity is characterized by a mixed portfolio of mainly thermal generation plants, relatively high shares of imports and exports, an increasing share of decentralized production, and a demand mainly coming from industrial users. This market increasingly becomes connected to its neighboring markets. The total size of the cross-border transmission capacity grew from 3.6 GW in 2006 to 5.1 GW in 2011, which is about 20% of the total domestic generation capacity of 28 GW (Table 1). This increase resulted from NorNed, the connection with the Nordic electricity market of 0.7 MW which was realized in May 2008, and BritNed, the connection with the UK market of 1 GW which was realized in March 2011. Despite the increase in import capacity, the annual level of imports did not increase (Table 1). The total domestic consumption declined in 2009 as a result of the economic crisis, but it returned to pre-crisis levels a few years later.

Besides the extension of the cross-border transmission capacity, a number of measures were taken to increase the efficiency of the utilization of the capacity, in particular market coupling and netting. Market coupling means that traders which are active in each of the coupled markets are able to submit orders to the commodity markets (i.e. power exchanges) without paying attention to the availability of cross-border capacity. The power exchanges set the clearing price given these orders and the available day-ahead transport capacity (Küpper et al., 2008). In November 2006, market coupling was introduced in the market with France and Belgium (the so-called Trilateral Market Coupling) while in November 2010 market coupling was realized on the German-Dutch border. The Trilateral Market Coupling appears to have reduced price differences across the borders (Dijkgraaf et al., 2007; NMa, 2011), implying that the markets have become more integrated. An

**Table 1: Key Indicators of the Dutch Electricity Market in 2006–2011, Average Value per Year***

| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|---|
| Prices and spreads (Euro/MWh) | | | | | | |
| day-ahead electricity price | 57 | 40 | 70 | 39 | 45 | 52 |
| spark spread | 7 | 3 | 8 | 9 | 2 | −5 |
| clean spark spread | −1 | 3 | −4 | 2 | −5 | −11 |
| dark spread | 36 | 13 | 28 | 18 | 16 | 15 |
| clean dark spread | 18 | 13 | 5 | 4 | 1 | 1 |
| Domestic production (TWh) | | | | | | |
| total | 99 | 105 | 108 | 113 | 118 | 113 |
| centralized | 67 | 70 | 67 | 72 | 76 | 70 |
| decentralized | 32 | 35 | 41 | 41 | 42 | 42 |
| Import (TWh) | 27 | 23 | 25 | 15 | 16 | 21 |
| Export (TWh) | 6 | 5 | 9 | 11 | 13 | 12 |
| Domestic consumption (TWh) | 120 | 123 | 124 | 118 | 121 | 122 |
| Installed capacity (GW) | | | | | | |
| total | 23.0 | 23.8 | 24.9 | 25.3 | 26.6 | 28.0 |
| centralized | 14.7 | 14.7 | 14.7 | 15.0 | 16.2 | 17.4 |
| decentralized | 8.3 | 9.1 | 19.2 | 10.3 | 10.4 | 10.6 |
| Import capacity (GW) | 3.6 | 3.6 | 4.0 | 4.3 | 4.3 | 5.1 |
| RSI | | | | | | |
| all hours | 1.26 | 1.32 | 1.39 | 1.63 | 1.56 | 1.69 |
| off super peak hours | 1.34 | 1.40 | 1.49 | 1.74 | 1.66 | 1.78 |
| super peak hours | 1.03 | 1.08 | 1.14 | 1.34 | 1.28 | 1.45 |
| HHI | | | | | | |
| all hours | 1369 | 1515 | 1525 | 1674 | 1598 | 1374 |
| off super peak hours | 1288 | 1440 | 1427 | 1615 | 1560 | 1347 |
| super peak hours | 1574 | 1710 | 1784 | 1829 | 1700 | 1447 |

Sources: prices: Bloomberg; Production and installed capacity: CBS; Import capacity: TenneT; Spreads, RSI, HHI: own calculations; Notes: super peak hours are defined as 10am to 7pm during working days. Note: * the domestic production, import, export and demand are aggregates per year.

additional benefit of market coupling is that traders are not able anymore to trade only locally (Gebhardt and Höffler, 2013).

In November 2008, netting was introduced on the connections with Belgium and Germany. With netting, the Transmission System Operator (TSO) nets out bidirectional long-term contracts. As a result, electricity can be exported or imported commercially, but physically it stays in the country where it is generated. This measure effectively increases the import (export) capacity which is available on the day-ahead market by the net size of the bidirectional long-term export (import) contracts (Mulder and Schoonbeek, 2013).

The growing interconnections make competition in the Dutch market more sensitive to developments in neighboring markets. In particular, the increasing capacity of wind and solar in Germany affects not only the German market, but also the Dutch market (Mulder and Scholtens, 2013). In the period of analysis, the German wind capacity almost doubled to about 25 GW, while the solar capacity in Germany grew from about 3 GW to almost 25 GW (Bundesministerium für Umwelt, 2012).

In the Dutch market, the level of installed capacity grew as well. The incumbent power firms extended their centralized generation capacity by 18% from 14.7 GW in 2006 to 17.4 GW in 2011 (Table 1). The decentralized generation capacity increased by about 25%: from 8.3 GW in 2006 to 10.6 GW in 2011. The latter increase is mainly realized by the horticultural industry, which changed from a net user of electricity into a net producer (Van der Velden and Smit, 2011). The ability of the horticultural firms to be active on the power market has been fostered by the development of options to store heat through warm-water basins. As a result, these firms are able to produce electricity during peak hours and to use the heat during off-peak hours.

In addition, electricity firms became more international. Before 2001, the supply side consisted of four nationally operating vertically-integrated players. Since then, a restructuring process started resulting in the new companies Essent, Nuon, Eneco and Delta. The former two companies have been taken over by the German firm RWE and the Swedish firm Vattenfall, respectively, while also the German firm E.ON and the Belgian firm Electrabel entered the Dutch market. Note that the Dutch market is characterized by full unbundling since 1998 when the independent transmission and system operator (TenneT) was established.

As a result of these developments, the HHI in the Dutch market, defined on the basis of the flexible generation capacity as well as import capacity, decreased significantly. The HHI based on production and import, however, does not show a declining trend over the past years (Table 1). The RSI increased strongly: in 2006 and 2007 the average RSI (of the marginal supplier per hour) during super peak hours (defined as from 10am to 7pm during working days) was about on the critical level of 1.05, but since then it rose strongly, indicating that the incumbent firms became less pivotal (see also Mulder and Schoonbeek, 2013). Partly also as a result of the above developments, the spread between the electricity price and the fuel prices declined. The average annual spark spread decreased from 7 euro per MWh in 20006 to -5 in 2011, while the dark spread decreased from 36 euro per MWh in 2006 to 15 euro in 2011 (Table 1).

## 4. EMPIRICAL MODEL

### 4.1 Calculating the Lerner Index

To measure the intensity of competition, we define the weighted average Lerner index as

$$LI_t = \sum_i \frac{(p_t - mc_{t,i})}{p_t} * m_{t,i} \tag{1}$$

where

$$m_{t,i} = \frac{Prod_{t,i}}{\sum_i Prod_{t,i}} \tag{2}$$

and $p$ refers to the day-ahead electricity price, $mc$ to the marginal costs per firm $i$, $m$ to the market share per firm and *Prod* to the production by the flexible generation capacity per firm, while $t$ is the index for hours. The ability for flexible operation is determined by the technical characteristics of a plant: open-cycle (OCGT) and combined-cycle gas turbines (CCGT) for instance have the ability to change the level of production relatively quickly without much effects on electrical efficiency. The technical characteristics, however, determine not fully whether a plant is actually used to respond to short-term circumstances as the production of a plant might be (partly) committed through long-term contracts. Therefore, we define the flexible generation capacity on the basis of the actual (revealed) production volatility; so, this capacity is viewed to be equal to the capacity which is not continuously dispatched over a relatively long period of time. We state that this capacity is unhedged, i.e. not covered by long-term contracts, implying that the profits on this capacity are affected by changes in the day-ahead prices. After all, what matters for supply decisions of firms are the inframarginal profits they can achieve by influencing prices.

The hourly marginal costs per firm are based on firm-specific hourly merit orders and aggregated levels of production. These marginal costs can be viewed to be perfectly competitive as they are fully based on marginal costs, independent of possible other (strategic) considerations (Borenstein et al., 2002). We call this the optimal dispatch.[1] The merit orders are based on the actual hourly available generation capacity per plant, technical characteristics of these plants and the daily prices for fuel ($p^f$) and $CO_2$ ($p^{CO_2}$). The technical characteristics used to calculate the hourly marginal costs per plant *j* are the thermal efficiency (*E*), the variable costs (*vc*) and the start-and-stop costs (*sc*). We also include an estimate of the opportunity costs (*oc*) of selling electricity on the day-ahead market. As a result, the hourly marginal costs per plant *j* are calculated as

$$mc_{j,t} = \frac{1}{E_j} * (p_t^f + p_t^{CO_2}) + vc_j + sc_{j,t} + oc_{j,t}. \tag{3}$$

The variable costs (*vc*) consist of variable operational and maintenance costs. These costs are plant specific, but they are assumed to be constant during a year. The start-and-stop costs (*sc*) reflect the fact that the dispatch of power plants has to be considered from a dynamic perspective (Müsgens, 2006; London Economics, 2007; Mansur, 2008; Arnedillo, 2011). Without having a dynamic dispatch model, we approach these costs by looking at the plant-specific historical average duration of uninterrupted production (*dup*) and the average costs of starting and stopping plants of different types. The latter depend on energy input (*ec*), the respective fuel price as well as the operational costs of starting and stopping (*omc*) (KEMA, 2007). This results in the following formula for the (expected) start-and-stop costs per plant per hour:

$$sc_{j,t} = \frac{(ec_j * p_t^f + omc_j)}{dup_j}. \tag{4}$$

From equation (4) follows that the start-and-stop costs are negatively related to the average duration of uninterrupted generation. Note that we implicitly assume that the average historical start-and-stop costs can be used as a measure for the expected start-and-stop costs.

The opportunity costs (*oc*) of selling electricity on the day-ahead market result from missing potential benefits on the intraday or balancing market if electricity is sold on the day-ahead market (Wilson, 2000; Harvey and Hogan, 2001; Bundeskartelamt, 2011). Intraday and balancing markets offer market participants options to adjust their positions in response to the latest developments in demand and supply during the day (Wolak, 2007). The existence of these costs may explain why plants sometimes are not dispatched while the day-ahead price exceeds their marginal costs. We estimate these opportunity costs as the moving average of the realized differences between

1. The alternative for using the optimal dispatch would be using the actual dispatch of each plant. That approach could, however, bias the results, as the marginal costs based on the actual dispatch may be increased because of strategic (withholding) decisions made by the power firms. As a result, the estimated Lerner index would be too low. In order to check the impact of using the optimal dispatch on the results, we conduct a sensitivity analysis with data on the actual dispatch (see Section 6).

the day-ahead price and the intraday price (*ip*) over a past period $s$ ( $= t-1 \ldots t-S$) where $w$ is used as weight for each observation:

$$oc_t = \frac{\sum_{s=-S}^{-1}(ip_s - p_s) * w_s}{\sum_{s=-S}^{-1} w_s}. \quad (5)$$

This moving average forms the expected value of the difference between these two prices. We assume that each historical observation has the same weight, implying that the opportunity costs are based on the unweighted average of past differences between the day-ahead and the intraday price. Note that this expected value might be negative, although in that case the marginal costs of a plant would not be affected.

Next to using the Lerner index as the measure of the intensity of competition, we calculate the annual operational profit per MW on plant level as an indirect indicator. After all, if competition intensifies the profit margin per plant likely reduces. We calculate the operational profit (*OP*) per plant $j$ per year $y$ as

$$OP_{j,y} = \frac{\sum_t^T (P_t^* - mc_{j,t}) * g_{j,t}}{IC_j}, \quad (6)$$

where $T$ is the number of hours in a year, $g$ is the level of production, $IC$ is the level of installed capacity per plant, and $P^*$ is the weighted average price for the different products (daily, monthly, quarterly and yearly) on the different markets (exchange and OTC).

### 4.2 Explaining the Lerner Index

We specify time-series models to explain the hourly development in the (weighted average) Lerner Index (see Eq. 7). The explanatory variables in the base model are the HHI based on production of flexible plants and import, net demand (*ND*), the temperature of river water above the environmental threshold (*RTR*), the production of wind power in Germany (*W*), the day-ahead price in the German market (*EEX*) in order to capture all other events in this market which might influence the Dutch market, and a trend variable (*Trend*). In the alternative model we extend this base model by also including variables capturing changes in the cross-border capacity. The physical extensions of the cross-border capacity (in particular the NorNed line and the BritNed line) are captured through hourly data on the available import capacity (*IC*), while the virtual extensions through market coupling with the neighboring countries ($l$) are captured through two dummies (*D_MC*), one for the coupling with the Belgian-French market and one for coupling with the German market.

$$\begin{aligned} LI_t = {} & \beta_0 + \beta_1 HHI_{t-1} + \beta_2 ND_{t-1} + \beta_3 RTR_t + \beta_4 W_t + \beta_5 EEX_{t-1} \\ & + \beta_6 Trend_t + \beta_7 IC + \sum_{l=1}^{2} \gamma_l D_{MC_{l,t}} + \varepsilon_t \end{aligned} \quad (7)$$

Although competition might especially vary during peak hours (Borenstein, et al., 2002), we include all hours in our analysis in order to be able to find more general results. In order to control for possible endogeneity, we include the lags of the explanatory variables *HHI*, *ND* and

*EEX*.[2] Using the lag of explanatory variables implies that endogeneity problems cannot occur, as the dependent variable in hour $t$ cannot affect independent variables in hour $t-1$.

We calculate the *HHI* on the basis of production by the flexible generation capacity in order to take into account the fact that in particular this capacity determines the ability of firms to behave strategically (Newbery, 2008). Moreover, because the intensity of competition also depends on potential supply from foreign firms (Arnedillo, 2011), we include the import (I) in the calculation of *HHI* (see Eq. 8). The import can partly be allocated to the domestic electricity producers as they have (limited) rights to book long-term cross-border capacity. As the remaining of the import can be assumed to come from numerous other players (traders), we need not to include their shares in the numerator of the *HHI*.

$$HHI_t = \sum_i \left( \frac{Prod_{i,t} + I_{i,t}}{\sum_i Prod_{i,t} + I_t} \right)^2 \tag{8}$$

The influence of the level of net demand is included in the model through the variable *ND* which measures the total domestic demand corrected for the supply by the decentralized generation units:

$$ND_t = G_t + I_t - E_t. \tag{9}$$

By definition the level of the net demand is equal to the aggregated level of generation by the centralized generation units (*G*) plus total imports (*I*) minus total exports (*E*). Note that total domestic demand is by definition equal to this net demand and the aggregated supply by decentralized production units.

We control for the fact that the producers sometimes face dispatch restrictions which affects the intensity of competition. As many (thermal) power plants in the Dutch market are located close to rivers, environmental restrictions to use river water for cooling purposes may restrict the dispatch (Mulder and Scholtens, 2013). If temperature in river water exceeds the threshold of 23 degrees Celsius, these power plants are forced to reduce production. For the German wholesale market, for instance, McDermott and Nilsen (2011) find that the electricity price rises by approximately 0.2% for every degree that the river temperature exceeds the regulatory threshold. We implement this restriction through a variable (*RTR*) measuring the number of degrees the actual temperature exceeds the threshold.

A fringe supplier which is relevant for competition in the Dutch market is the horticulture industry. The supply by horticultural firms, using Combined Heat Power (CHP) plants, is related to the outside temperature as it is mainly a by-product of the production of heat and $CO_2$. The impact of this fringe supply is (indirectly) measured through *ND*, as the value of the net demand is related to the level of supply from fringe suppliers such as the horticultural firms. Therefore, we do not need to include this fringe supply explicitly.

2. For all these variables (*HHI*, *ND* and *EEX*) hold that the value in hour t is strongly correlated to the levels in hour $t-1$ (the correlation coefficients are 0.96, 0.95, 0.89, respectively). Therefore, we do not lose much information by using the lagged values. The latter also follows from the fact that the correlation coefficient between the Lerner index and *ND* is 0.61, which is about equal to the correlation coefficient between the Lerner index and the lagged *ND* (0.56). The respective values for Lerner index and *HHI* are 0.47 and 0.45 and for Lerner index and *EEX* 0.55 and 0.51. Note that we control for the autocorrelation in the model by including AR variables (see Section 6.2).

The intensity of competition is likely also to be affected by the (fringe) supply coming from wind and solar. Both wind-powered generation capacity and the amount of solar cells have grown strongly in recent years, in particular in Germany (Mulder and Scholtens, 2013). This significant increase in supply probably likely has an impact on competition in the German market, indirectly influencing the Dutch market. As data is available on supply from German wind generation capacity for each hour in the period 2006–2011, we are able to include this variable in our model. As for solar supply no such time series are available, we cannot directly estimate the impact of this supply. This effect is, however, included in the effect of the *EEX* price, since the German day-ahead price results from all short-term events affecting supply and demand in the German market. By including the (lagged) *EEX* price, we control for the influence of all the remaining factors in the German market on the Lerner index in the Dutch market. As in Section 6.2 is shown, including both the German wind supply and the German electricity price does not result in multicollinearity.

The impact of changes in the cross-border capacity is measured through the physical size of total import capacity and dummies capturing the introduction of market coupling. Because of a lack of suitable data, it is impossible to include a measure for netting.[3]

As the Lerner index might also be affected by specific time patterns which are not yet captured by the above variables, we conduct a sensitivity analysis by also including dummies for hour of the day, day of the week and month of a year. In all model specifications, we include a trend variable to control for a possible long-term time trend.

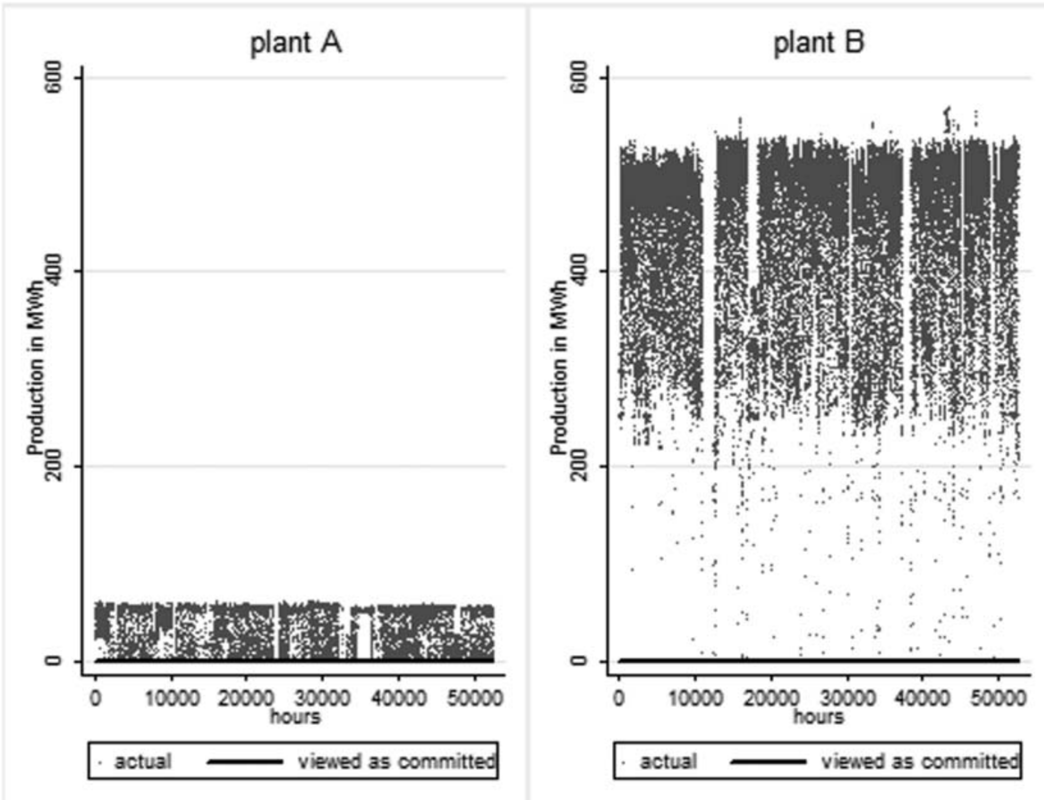
## 5. DATA

For the calculation of the Lerner index, we use hourly data on the centralized production units, obtained from the Netherlands Authority for Consumers and Markets (hereafter: ACM database). In the Dutch market, electricity companies are legally obliged to submit all their data regarding the dispatch of their plants to the regulator. The ACM database includes hourly data on the available generation capacity as well as the level of production for all centralized production units in the Dutch market over the period 2006–2011.

Because this database does not say by what type of contracts the production is sold, we measure the not-yet-committed generation via the size of the generation by the flexible generation capacity. Hence, we use the revealed production volatility to determine the capacity of each plant which is available in the day-ahead market. The production volatility of a plant is determined by inspecting the production profile during the past years on hourly basis. Figure 1 shows the dispatch of two plants as example. Plant A, a CCGT plant, shows hourly production levels fluctuating from zero to the maximum capacity of 60 MW, while the hourly production level of Plant B, a coal-fired plant, also fluctuates, but almost constantly above 250 MW. We assume that the latter level can be viewed as already committed production which is unaffected by price changes in the day-ahead market. The share of committed production per plant varies strongly among plants with a median of 44% over all plants and all hours. This high percentage is in in line with the fact that power producers sell a significant portion on forward markets (NMa, 2011). It appears that the committed

3. Capturing the impact of netting by a time dummy would not be correct as the day-ahead import capacity is highly volatile, affecting the impact of netting. Including the day-ahead capacity as an alternative measure would neither be correct, as this capacity is also affected by other factors, as the size of total transfer capacity, which is already included in the model as ‘import capacity’.

**Figure 1: Actual and Committed Production of Two Different Plants in 2006–2011, per Hour**




Source: ACM database; own calculations

**Table 2: Descriptives of Cost Elements per Power Plant (in Euro/MWh), Average Values in 2006–2011**

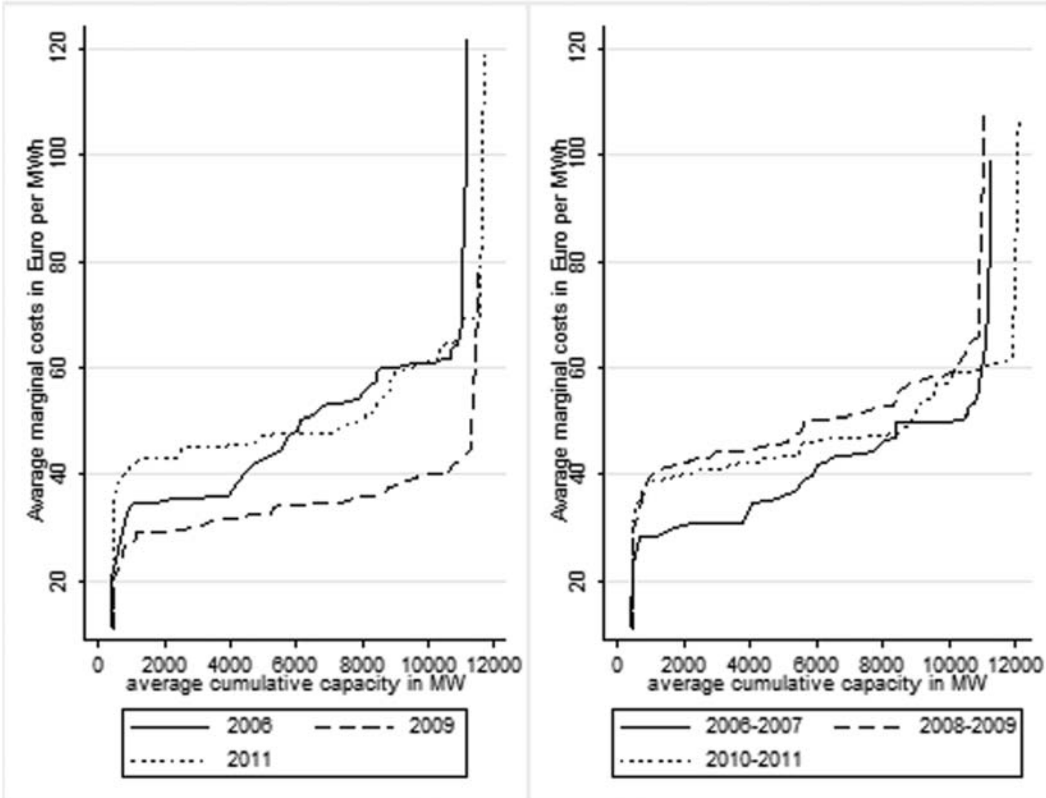
| Variable | Mean | Standard deviation | Minimum | Maximum |
|---|---|---|---|---|
| Variable costs (vc) | 2.3 | 0.8 | 0 | 4.5 |
| Start-and-stop costs (sc) | 1.5 | 3.3 | 0 | 32.5 |
| Opportunity costs (oc) | −0.3 | 1.6 | −93 | 64 |

Source: ACM database; own calculations.

capacity refers mostly to steam-coal and steam-gas plants, while the OCGT and CCGT plants are almost fully operated on a flexible basis.

The ACM database also contains descriptions of the technical characteristics of each plant, such as generation technology, maximum technical capacity, fuel type and how fuel efficiency is related to the utilization of a plant. By combining these data with data on fuel prices, we are able to determine the hourly marginal costs of each plant. Table 2 gives the descriptives of the variable costs, the start-and-stop costs and the opportunity costs.

**Figure 2: Aggregate Merit-Order Curves, 2006–2011 (Average per Period)**



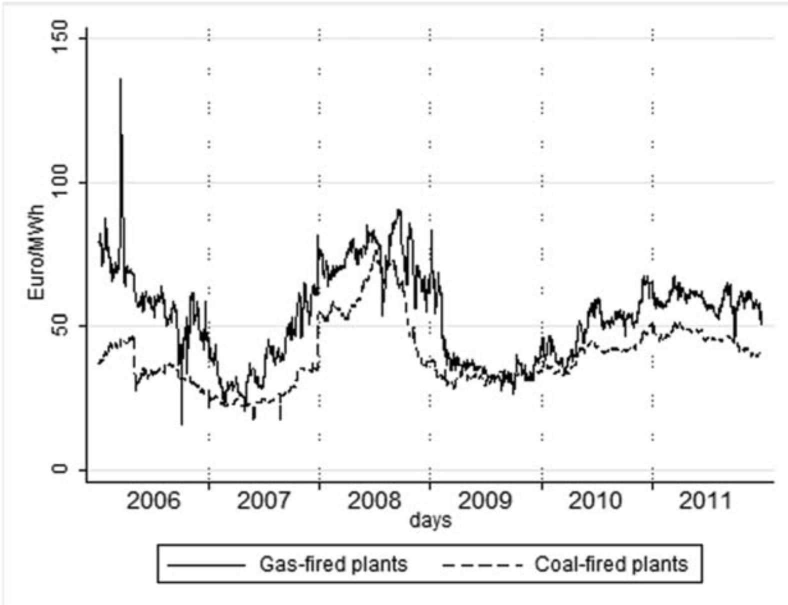

Source: ACM database; own calculations

Figure 2 presents the average aggregate merit-order curves. We see that in 2006 the merit order was much steeper than in the other years. The panel on the right in Figure 2 shows the average merit orders in the periods 2006–2007, 2008–2009 as well as 2010–2011. We see that in the second period the merit order is flatter than in the first one, while the last period shows an almost horizontal merit order for a significant part of the curve.

Changes in the merit-order curve mainly follow from changes in the prices of fossil fuels. Compared to 2006, the difference in the marginal costs of coal-fired and gas-fired plants was smaller in the following years (Figure 3). In 2009, for instance, in particular the gas price was relatively low (Table 3). Comparing the aggregate merit-order curve with the realized prices on the day-head exchange and produced quantities (Figure 4), we see that in 2006 these prices were significantly above the level of marginal costs during many hours. Note that the scales of both figures differ. We see that the electricity price frequently was above the level of 200 euro/MWh, while the average marginal costs were far below 100 euro/MWh in 2006. We also see that in 2009 and 2011 prices rose less when production levels increased.

The left panel of Figure 5 shows that a significant group of power plants was hardly dispatched in 2011, while the right panel indicates that this mainly refers to relatively small plants: the 30% of the plants with less than 2000 operating hours in 2011 had a share of no more than

**Figure 3: Average Marginal Costs of Coal-Fired Plants and Gas-Fired Plants in 2006–2011, per Day**




Source: ACM database; own calculations.

**Table 3: Average Annual Electricity Price and Fuel Prices in 2006–2011**

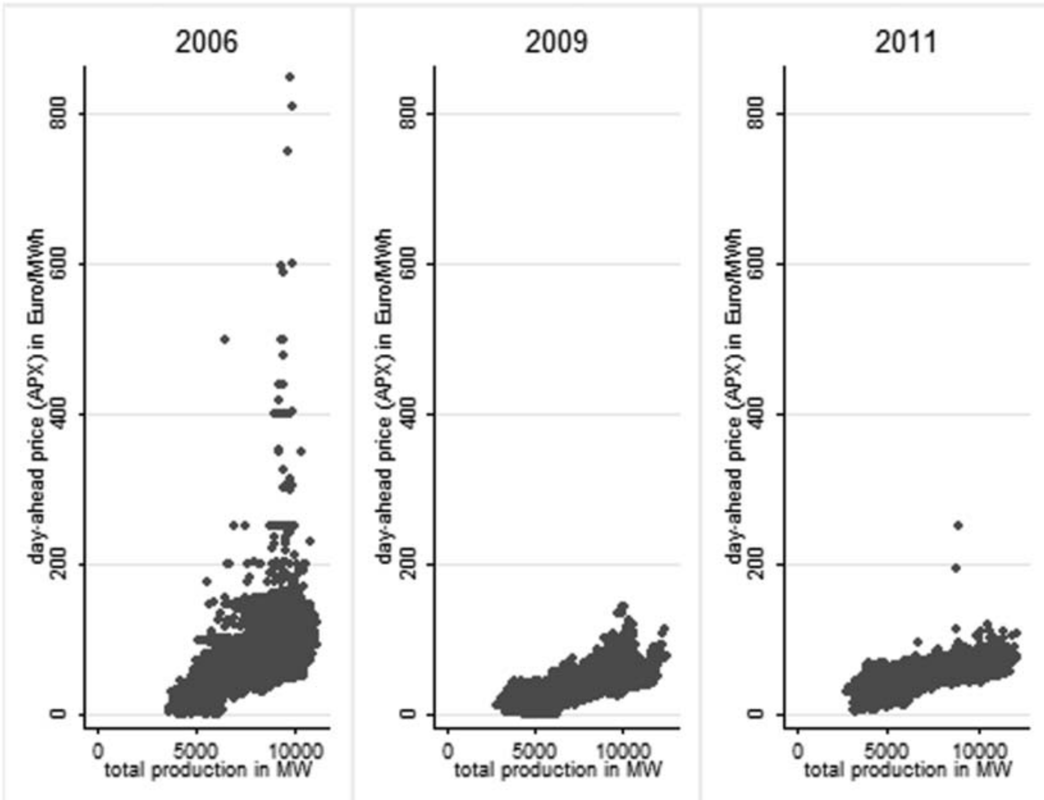
| Prices | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|---|
| Day-ahead electricity price (APX; Euro/MWh) | 57 | 40 | 70 | 39 | 45 | 52 |
| Day-ahead gas price (TTF; Euro/MWh) | 20 | 15 | 25 | 12 | 17 | 23 |
| Coal price (Euro/ton) | 7 | 9 | 14 | 7 | 10 | 13 |
| $CO_2$ price (Euro/ton) | 17 | 1 | 22 | 13 | 14 | 13 |

Source: Bloomberg.

20% in aggregated capacity. Note that the annual hours of dispatch is measured as all hours having a positive level of production. The decrease in the number of operating hours is not related to higher demand variability as the standard deviation of net demand was stable, but follows from a lower level of net demand plus changes in relative fuel prices making the dispatch of some plants uneconomic (see Figure 3 and Table 4).

The ACM database is also used to calculate the HHI and the level of net demand. The HHI varies strongly from hour to hour, but is fairly stable on an annual basis (Table 4). The fluctuations in the HHI are closely related to the level of import, given the correlation coefficient between these two variables of 0.63. The net demand clearly shows a declining trend: in 2011 the average annual level is about 15% lower than the 2006 level. This decline results from an increased production by decentralized units, but it is also affected by the decrease in the level of total domestic consumption of electricity (Table 1). The import capacity has grown since 2006 as a result of the

**Figure 4: Realized Hourly Day-Ahead Prices and Production Levels in 2006, 2009 and 2011, per Hour**




Source: day-ahead price (APX): Bloomberg; production: own calculations (ACM database)

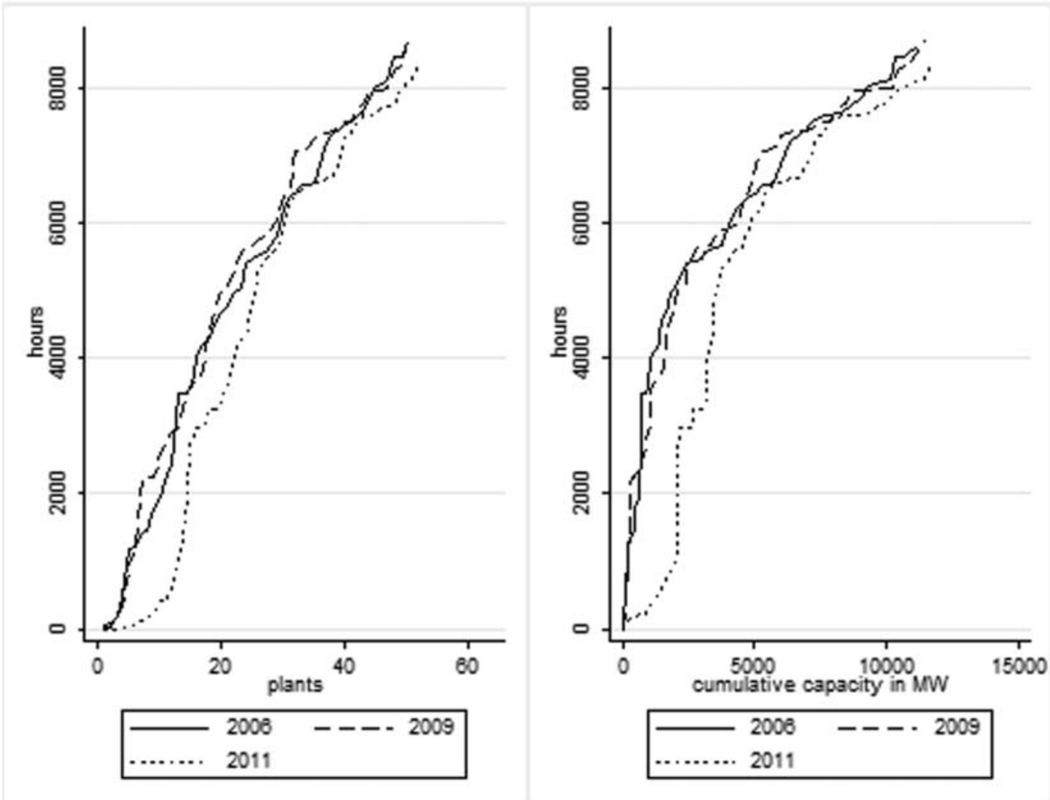
NorNed line, connecting the Dutch market to the Scandinavian market (May 2008) and the BritNed line, connecting the Dutch market to the UK market (March 2011).

The river temperature refers to the temperature measured in the river Lek, close to Hagesteijn, a village located in the middle of the Netherlands. These data are derived from Rijkswaterstaat. Except in 2007 and 2011, the river temperature exceeded the environmental threshold of 23 degrees Celsius for a number of days in each year.

For wind, we are able to include the actual production in Germany on the basis of data published on their websites by the German TSOs (Amprion, 50Hertz, TenneT and Transnet). The production of wind energy in Germany grew as a result of the increase in wind generation capacity in this country. Table 4 clearly shows that this supply has a high volatility following from the intermittent character of this generation technique. As said in Section 4, data on the supply of solar energy during the whole period is not available.

As a measure for all other events in the German day-ahead market affecting the Dutch market, we use the German day-ahead prices from the European Energy Exchange (EEX). The movements in these prices reflect changing conditions in the German market, which possible affect the Dutch market. Table 4 shows the volatility of the EEX price declined during 2006–2011.

**Figure 5: Annual Hours of Dispatch, per Plant and per Cumulative Level of Capacity in 2006, 2009 and 2011**




Source: ACM database; own calculations.

**Table 4: Descriptives of the Explanatory Variables in the Time-Series Analysis in 2006–2011 (Averages per Year; Standard Deviation between Brackets)**

| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|---|
| HHI (index, x 10,000) | 0.14 | 0.15 | 0.15 | 0.17 | 0.16 | 0.14 |
| | (0.03) | (0.03) | (0.03) | (0.03) | (0.03) | (0.03) |
| Net demand (GWh) | 10.26 | 9.86 | 9.28 | 8.49 | 9.15 | 8.79 |
| | (1.74) | (1.67) | (1.56) | (1.50) | (1.57) | (1.52) |
| Import capacity (GW) | 3.58 | 3.56 | 4.05 | 4.33 | 4.25 | 5.11 |
| | (0.28) | (0.30) | (0.53) | (0.33) | (0.40) | (0.57) |
| River temperature above 23 degrees Celsius | 0.13 | 0 | 0.01 | 0.02 | 0.05 | 0 |
| | (0.48) | (0) | (0.10) | (0.13) | (0.24) | (0) |
| Wind production Germany (GWh) | 3.29 | 4.39 | 4.53 | 4.24 | 4.05 | 5.11 |
| | (3.10) | (3.79) | (4.02) | (3.60) | (3.64) | (4.53) |
| EEX (euro/MWh) | 51.9 | 38.7 | 68.5 | 40.9 | 45.6 | 52.0 |
| | (26.1) | (26.5) | (27.0) | (17.4) | (12.8) | (12.4) |

Sources: wind production: German TSOs (Amprion, 50Hertz, TenneT and Transnet); river temperature: www.rijkswaterstaat.nl/water; Import capacity: TenneT; EEX: Bloomberg; other variables: own calculations based on the ACM database.

## 6. RESULTS

### 6.1 The Lerner Index

We find that the Lerner index on average over all hours in a year hardly changed in the period 2006–2011 (Table 5). However, the annual averages hide the fact that the Lerner index changed significantly on hourly basis, which is reflected by the duration curves (Figure 6). In 2011, the duration curve was flatter than in 2009 and much flatter than in 2006. The average value during super peak hours decreased from 0.23 in 2006 to 0.03 in 2011, indicating that competition became

**Table 5: Weighted average Lerner index and Operational Profit in the Dutch Electricity Market in 2006–2011 (averages per year)**

| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|---|
| Lerner index | | | | | | |
| all hours | −0.06 | −0.03 | −0.07 | −0.01 | −0.08 | −0.08 |
| off super peak hours | −0.17 | −0.15 | −0.16 | −0.08 | −0.14 | −0.13 |
| super peak hours | 0.23 | 0.27 | 0.16 | 0.20 | 0.09 | 0.03 |
| Operational profit ( × 1000 Euro per MW) | 137 | 107 | 127 | 96 | 68 | 67 |

**Figure 6: Duration Curves of the Weighted Average Lerner index and Net Demand in 2006, 2009 and 2011**

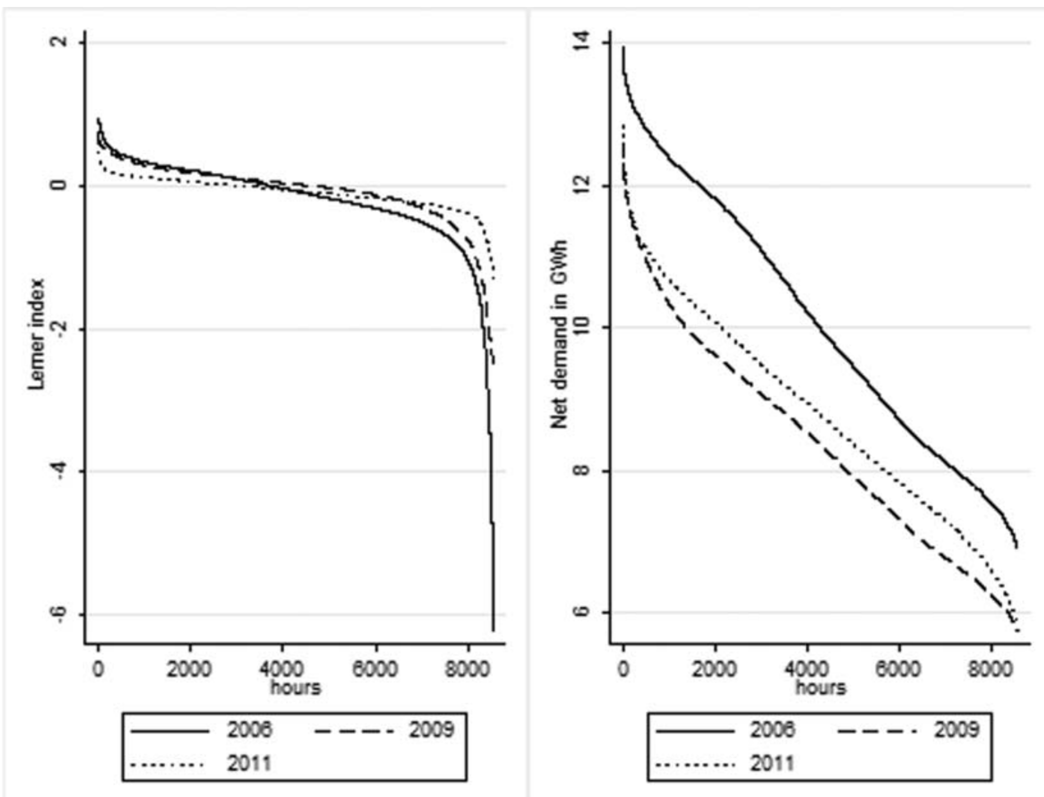


**Table 6: Decomposition of the Change in the Weighted Average Lerner Index, 2006–2011**

| Variable | Coefficient (standard error) | Standard deviation in data | Relative effect* |
|---|---|---|---|
| constant | −0.15 (0.002)*** | | |
| Unweighted Lerner index | 0.84 (0.001)*** | 0.30 | 0.25 |
| HHI production (excluding import) | 1.19 (0.01)*** | 0.04 | 0.05 |
| Adjusted $R^2$ | 0.92 | | |

Note: * relative effect = change in dependent variable as a result of a one-standard-deviation change in the explanatory variables; *** refers to 1% significance level.

more intensive in these hours (Table 5). In the off super peak hours, the average Lerner index did not change much, but also here the duration curve became flatter. The change in the weighted average Lerner index is mainly a level effect instead of a composition effect as this change mainly follows from the change in the unweighted Lerner index (Table 6). Figure 6 shows that the change in the Lerner index duration curves cannot be fully explained by changes in the level of net demand: the load duration in 2011 is above the 2009 curve while the Lerner index duration curve is much flatter in 2011.

The annual operational profit per MW of installed capacity reduced significantly: from 137,000 euro/MW in 2006 to 67,000 euro/MW in 2011.[4] This is also reflected by the duration curve of the annual operational profit on plant level (Figure 7, left panel). In 2011, 20 out of 50 power plants made no operational profit at all, while in 2006 only 5 out of 50 had zero operational profits. From the right panel of Figure 7, we learn that those plants are relatively small as their share in total capacity was negligible in 2006 and about 20% in 2011. The decline in the operational profit per MW of installed capacity is equally related to both the decrease in the net demand and the increase in competition, given the fact that the respective correlation coefficients are about 0.60 in both cases.

### 6.2 Results Time-Series Analysis

We conduct a time-series analysis to assess the influence of a number of explanatory variables on the Lerner index. It appears that the correlation coefficient between net demand and the Lerner index is relatively high (Table 7). The correlation coefficients between the explanatory variables are low, except for the relation between net demand and the EEX day-ahead price. We regressed each of the explanatory variables on the other dependent variables, resulting in values for correlation coefficients far below the threshold of 0.80, indicating that the model does not suffer from multicollinearity (Table 8).

Tests on unit roots with the Elliott-Rothenberg Stock test show that the data seem to be stationary (Table 9). Hence, we include all variables as levels. Analysis of the correlogram of the dependent variable made clear that autocorrelation exists (see Franses, 1998). In order to correct for this, we estimate the time-series model with additional AR explanatory variables: AR(1) and AR(24). The ARCH-LM test indicates that the OLS-regression suffers from ARCH-effects, imply-

4. We use short-term (day-ahead) prices as well as different forward prices (monthly, quarterly and yearly ahead) in order to estimate the operational profits over the total level of production. The spot market prices were on average 51, with a minimum 0.01 and a maximum of 850 Euro/MWh during 2006–2011. The price index has as average 57, with a minimum of 34 and a maximum of 224 Euro/MWh.

**Figure 7: Operational Profit per Plant and per Cumulative Level of Capacity in 2006, 2009 and 2011 (Annual Aggregates per MW)**

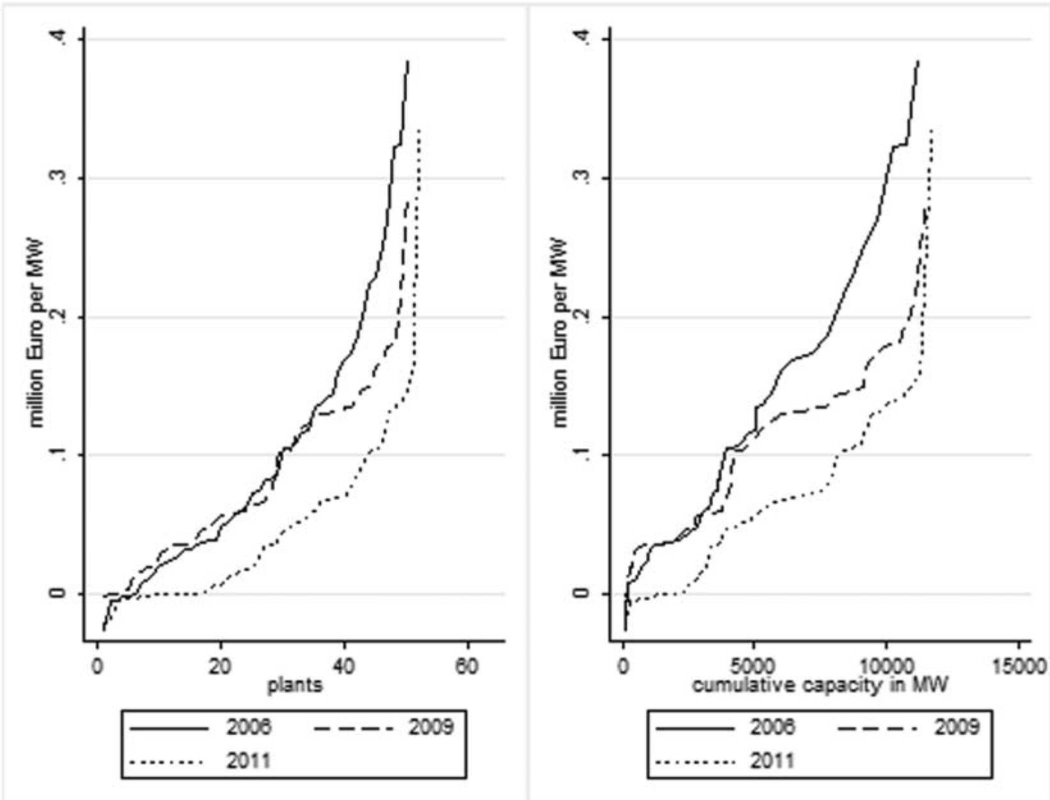



**Table 7: Correlation Matrix of Variables in Time-Series Analysis, 2006–2011 (excluding Dummies)**

| Variables | LI | HHI | Net demand | Import capacity | Wind Germany | River temp |
|---|---|---|---|---|---|---|
| HHI | 0.47 | | | | | |
| Net demand | 0.61 | 0.34 | | | | |
| Import capacity | −0.03 | −0.13 | −0.20 | | | |
| Wind Germany | −0.06 | 0.05 | −0.001 | −0.17 | | |
| River temp restriction | 0.03 | −0.06 | 0.03 | −0.04 | −0.11 | |
| EEX | 0.55 | −0.34 | −0.54 | 0.10 | −0.14 | 0.06 |

ing that the OLS estimators are less precise which is caused by clustered volatility. Therefore, we add a variance equation. It appears that an ARCH(2,2) specification performs best in terms of removing ARCH-effects and realizing the lowest value on the Akaike information criterion.

We estimated our model in 5 versions (Table 10). The first column refers to the base model and the second one to the alternative model which includes the variables referring to the cross-border transmission capacity. Both models are estimated for the full period of 2006–2011. The other three columns refer to the base model, but now estimated for three sub periods: 2006–2007, 2008–

**Table 8: Results of Tests on Multicollinearity: R-squared of Equations with Explanatory Variables taken as the Independent Variable**

| Variable | Model without time dummies | Model with time dummies |
|---|---|---|
| HHI | 0.23 | 0.39 |
| Net demand | 0.14 | 0.45 |
| River temperature restriction | 0.05 | 0.26 |
| Wind supply Germany | 0.09 | 0.15 |
| EEX | 0.33 | 0.40 |
| Import capacity | 0.19 | 0.32 |
| D_MC_Belgium_France | 0.35 | 0.45 |
| D_MC_Germany | 0.30 | 0.33 |

**Table 9: Results of Unit-Root Test**

| Variables | Elliot-Rotherberg Stock DF-GLS statistic |
|---|---|
| LI | −3.1 |
| HHI | −7.4 |
| Net demand | −17.6 |
| Import capacity | −6.5 |
| Wind supply Germany | −14.4 |
| River temperature restriction | −11.4 |
| EEX | −9.6 |

Note: Critical values are: −2.6 (1%), −1.9 (5%) and −1.6 (10%)

2009 and 2010–2011, respectively. By these models we test whether the influences of the explanatory factors changed over time.[5]

In all models, we find that both the HHI and the level of net demand have a positive influence on the Lerner index, as expected. The more concentrated the market (in terms of flexible generation and import) and the higher the net demand, the less intensive competition appears to be. Both relationships became, however, less strong. The coefficient for HHI declined from 1.65 in the first period to 1.26 in the last one. This result is also found when we use the actual dispatch instead of the optimal dispatch (see Appendix 1), but when we include time dummies this effect is less clear. The decline in the coefficient for HHI may indicate a higher price elasticity if firms still compete in a Cournot manner, but this decline may also imply that firms move away from Cournot competition.

The coefficient for net demand also decreased: it was 0.11 in the first period, 0.07 in the second one and 0.02 in the last one. This decline of the coefficient may result from more Bertrand-like competition resulting in prices more strongly related to marginal costs, while the level of demand become less important for the market outcomes.

5. In order to check the influence of the way we calculate the system marginal costs, we conduct a sensitivity analysis in which we use the actual dispatch per plant instead of the optimal dispatch (see Appendix 1). Comparing these results with the results of the model with the optimal dispatch (Table 10, 2nd column with results), we see that the coefficients and significance levels are quite similar. Therefore we conclude that our results are robust for the way we have defined the (system) marginal costs. The advantage of using the optimal dispatch is that this dispatch is not affected by other factors, including possible strategic consideration of suppliers, making this approach more suitable for our purpose.

**Table 10: Effects of Explanatory Variables on the Lerner Index, 2006–2011**

| Explanatory variables | 2006–2011, excl. cross-border measures | 2006–2011, incl. cross-border measures | 2006–2007 | 2008–2009 | 2010–2011 |
|---|---|---|---|---|---|
| constant | −0.95*** | −0.82*** | −1.44*** | −1.44*** | −0.48*** |
| | (0.01) | (0.02) | (0.03) | (0.03) | (0.04) |
| HHI (−1) | 2.06*** | 2.01*** | 1.65*** | 1.07*** | 1.26*** |
| | (0.03) | (0.03) | (0.11) | (0.07) | (0.03) |
| Demand(−1) | 0.06*** | 0.06*** | 0.11*** | 0.07*** | 0.02*** |
| | (0.0008) | (0.001) | (0.002) | (0.002) | (0.001) |
| River temp | 0.02 | 0.02 | 0.02 | 0.01 | 0.04*** |
| | (0.01) | (0.01) | (0.02) | (0.03) | (0.02) |
| Wind Ger | −0.005*** | −0.007*** | −0.006*** | −0.003*** | −0.002*** |
| | (0.0003) | (0.0003) | (0.0009) | (0.0006) | (0.0003) |
| EEX(−1) | 0.002*** | 0.002*** | 0.0006*** | 0.002*** | 0.006*** |
| | (0.00002) | (0.00002) | (0.00006) | (0.00003) | (0.00008) |
| Import capacity | | −0.04*** | | | |
| | | (0.003) | | | |
| D_MC_Be_Fr | | 0.006 | | | |
| | | (0.02) | | | |
| D_MC_Ger | | −0.05*** | | | |
| | | (0.01) | | | |
| Trend | 0.0000003 | 0.000003*** | 0.000005** | 0.00002*** | 0.000006*** |
| | (0.0000003) | (0.0000005) | (0.000002) | (0.000001) | (0.0000009) |
| AR(1) | 0.69*** | 0.69*** | 0.71*** | 0.67*** | 0.64*** |
| | (0.002) | (0.002) | (0.005) | (0.004) | (0.004) |
| AR(24) | 0.21*** | 0.21*** | 0.18*** | 0.19*** | 0.24*** |
| | (0.002) | (0.002) | (0.004) | (0.004) | (0.003) |
| *Variance equation* | | | | | |
| Res.$(-1)^2$ | 0.34*** | 0.34*** | 0.29*** | 0.39*** | 0.36*** |
| | (0.003) | (0.007) | (0.006) | (0.005) | (0.004) |
| Res.$(-2)^2$ | −0.33*** | −0.34*** | −0.28*** | −0.39*** | −0.35*** |
| | (0.003) | (0.008) | (0.006) | (0.005) | (0.004) |
| GARCH(−1) | 1.38*** | 1.38** | 1.40*** | 1.32*** | 1.36*** |
| | (0.006) | (0.005) | (0.02) | (0.01) | (0.009) |
| GARCH(−2) | −0.38*** | −0.38*** | −0.40*** | −0.32*** | −0.36*** |
| | (0.006) | (0.005) | (0.02) | (0.01) | (0.009) |
| Adjusted $R^2$ | 0.79 | 0.79 | 0.81 | 0.78 | 0.79 |
| F stat. ARCH LM | 0.29 | 0.28 | 0.98 | 0.49 | 0.63 |
| N obs. | 49,281 | 49,281 | 15,898 | 16,432 | 16,951 |

Note: *; **; *** refer to 10%, 5% and 1% significance levels, respectively.

The model results also show that when the temperature of river water exceeds the environmental threshold of 23 degrees Celsius, the Lerner index is higher, although this finding is only significant in the last period. This result indicates that a restriction on the supply from power plants using river water for cooling purposes reduces the intensity of competition, which is consistent with the findings of McDermott and Nilsen (2011).

The level of competition in the Dutch electricity markets appears to be positively influenced by the supply of wind power from Germany, given its negative influence on the Lerner index. The more electricity is produced by German wind mills, the lower the Lerner index in the Dutch markets. Interestingly, this relationship is fairly constant over time while the German wind-generation capacity increased dramatically during 2006–2011. Possibly, the impact of German wind supply on the Dutch market is hindered by cross-border constraints (Mulder and Schoonbeek, 2013).

The impact of other events in the German market, measured by the (lagged) EEX price, on the Dutch market grew over the period of analysis: in the last period the coefficient for the EEX price is ten times bigger than in the first period. This result indicates that that these markets became more integrated.

We find that increases in the cross-border transport capacity enlarged competition in the Dutch market. This holds in particular for the physical extension through the new interconnections with the Scandinavian and the UK market and the implementation of market coupling between the Dutch market and the German market. In all model specifications we find statistically significant negative effects of these variables on the Lerner index. For the trilateral market coupling between the markets in the Netherlands, Belgium and France, however, we find indications for a negative effect on competition in the Dutch market.

As a sensitivity check, we also estimated the model by including time dummies for the hours of the day, the days of the week and the months of the year (see Appendix 2). We find that there exist several time patterns which are not yet covered by the other explanatory variables. Early in the morning the Lerner index appears to be relatively low, while at noon and early in the evening, the Lerner index is relatively high. This pattern fits well with the load profile during a day. The day of the week and the month of the year also have an effect on the Lerner index. In the last two periods, the effect of the time dummies is significantly smaller than in the first period. Note that including the time dummies hardly affects the results of the other explanatory variables.

## 7. CONCLUSIONS

Since the liberalization of electricity wholesale markets in the 1990s, a large number of authors have pointed at the vulnerability of these markets to competition problems. In order to improve competition, governments have taken a number of regulatory measures to reduce the ability of electricity producers to abuse market power. Several of these measures are directed at integrating national markets into larger regional markets. Using hourly data of centralized units on plant level and engineering-costs estimates, we analyze to what extent the intensity of competition in the Dutch wholesale electricity market changed over 2006 – 2011. We measure the intensity of competition by the weighted average Lerner index. We find that, during super peak hours, this index declined from 0.23 in 2006 to 0.03 in 2011. The rise in the intensity of competition in the Dutch market occurred in spite of international acquisitions of major Dutch energy companies, indicating that they did not hinder the development of competition, which is often mentioned as a serious risk in energy markets (see e.g. Jamasb and Pollitt, 2005).

The increase in competition reduced prices for electricity users at the expense of the operational profits of electricity producers. Note that these profits not only reduced because of this price effect, but also as a result of the lower net demand. Besides the distributional effect of more intensive competition, the effect on allocative efficiency is likely modest given the low price elasticity of demand. The productive efficiency of electricity generation rose, despite of the lower utilization rates of power plants, from 0.39 in 2006 to 0.42 in 2011.[6] This increase can possibly partly be attributed to the enlarged competition, as was also found by Craig et al. (2013) for the electricity markets in the United States.

6. Net electricity production was 285 PJ in 2006 and 308 PJ in 2011, while energy use was 723 PJ and 727 PJ, respectively. Source: CBS, Statline: http://statline.cbs.nl/StatWeb/default.aspx.

We find indications that the increase in competition in the Dutch market can be attributed to three main factors: extension of the available cross-border capacity, a higher price elasticity of net demand and more Bertrand-like competition.

The extension of the cross-border connections occurred partly through the establishments of new connections (with the Nordic as well as the UK market) and partly through a more efficient utilization of the existing connections with Germany by means of market coupling. These results indicate that the integration of the Dutch market with the neighboring markets improved competition in the Dutch market, as was already expected by for instance Hobbs, Rijkers and Boots (2005). For the trilateral market coupling between the Dutch, Belgian and French market, however, we do not find that this improved competition in the Dutch market, although it resulted in less price differences between these markets (Dijkgraaf et al., 2007; NMa, 2011). This result may be related to the fact that the Belgian and French markets were far more concentrated than the Dutch market. Overall, we conclude that fostering market integration can be an effective measure to stimulate competition. Note, however, that the effectiveness depends on, among others, the way market coupling is precisely implemented (Oggioni and Smeers, 2013).

The decline in the coefficient for the HHI may suggest that the price elasticity of net demand increased. Note that the net demand refers to the total domestic demand minus the supply from decentralized generation. Hence, the increase in the price elasticity possibly resulted from the increase in the capacity for decentralized generation, which was in 2011 about 25% larger than in 2006 (Table 1). From this we conclude that fostering the supply from decentralized generation may improve competition in electricity wholesale markets.

The decline in the coefficient for HHI may also indicate that firms moved away from Cournot competition. Indications for more Bertrand-like competition, in which prices are more strongly related to the marginal costs, can be seen in the declining coefficient for net demand. Such a change in competitive behavior may be triggered by the increase in generation and import capacity while the level of net demand decreased. Another factor which possibly contributed to this change in competitive behavior is the fact that the merit-order curves became flatter during the period of analysis (see Figure 2). A flatter merit-order curve reduces the ability of players to raise prices since the next plant (firm) in the merit order has only slightly higher marginal costs. Note that we use the merit-order curves as approximations of the bid curves on the power exchange. Further research is needed to precisely assess the way electricity producers compete and how that has possibly changed.

The lessons learned from the Dutch experience are that increased connection with neighboring countries and enlarged capacity of decentralized generation may foster competition and, hence, result in more competitive prices. These lessons may be valid for other countries, in particular those where supply mainly comes from a limited number of centralized generation firms, while connections with neighboring countries are not yet well-developed.

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**APPENDIX 1: Sensitivity Analysis: Results of Regression using Actual Dispatch Data**

| Explanatory variables | 2006–2011, excl. cross-border measures | 2006–2011, incl. cross-border measures | 2006–2007 | 2008–2009 | 2010–2011 |
|---|---|---|---|---|---|
| constant | −1.31*** | −1.24*** | −2.17*** | −1.78*** | −0.93*** |
| | (0.01) | (0.02) | (0.03) | (0.04) | (0.05) |
| HHI (−1) | 2.53*** | 2.49*** | 2.42*** | 1.48*** | 1.69*** |
| | (0.04) | (0.04) | (0.13) | (0.08) | (0.04) |
| Demand(−1) | 0.07*** | 0.07*** | 0.15*** | 0.08*** | 0.02*** |
| | (0.0008) | (0.0008) | (0.003) | (0.002) | (0.001) |
| River temp | −0.003 | 0.001 | 0.03 | 0.03 | 0.003 |
| | (0.02) | (0.02) | (0.03) | (0.04) | (0.02) |
| Wind Ger | −0.004*** | −0.006*** | −0.006*** | −0.001 | −0.002*** |
| | (0.0003) | (0.0004) | (0.001) | (0.0006) | (0.0004) |
| EEX(−1) | 0.002*** | 0.002*** | 0.0006*** | 0.002*** | 0.007*** |
| | (0.00002) | (0.00002) | (0.00008) | (0.00003) | (0.0001) |
| Import capacity | | −0.04*** | | | |
| | | (0.003) | | | |
| D_MC_Be_Fr | | 0.08*** | | | |
| | | (0.02) | | | |
| D_MC_Ger | | −0.02 | | | |
| | | (0.01) | | | |
| Trend | 0.000004 | 0.000005*** | 0.00004*** | 0.00003*** | 0.00000003 |
| | (0.0000003) | (0.0000006) | (0.000003) | (0.000001) | (0.000001) |
| AR(1) | 0.70*** | 0.70*** | 0.72*** | 0.67*** | 0.67*** |
| | (0.002) | (0.002) | (0.004) | (0.004) | (0.004) |
| AR(24) | 0.20*** | 0.20*** | 0.18*** | 0.20*** | 0.23*** |
| | (0.002) | (0.002) | (0.004) | (0.004) | (0.003) |
| *Variance equation* | | | | | |
| Res.(−1)$^2$ | 0.36*** | 0.37*** | 0.34*** | 0.41*** | 0.35*** |
| | (0.003) | (0.002) | (0.002) | (0.005) | (0.004) |
| Res.(−2)$^2$ | −0.36*** | −0.36*** | −0.34*** | −0.41*** | −0.34*** |
| | (0.003) | (0.003) | (0.002) | (0.005) | (0.004) |
| GARCH(−1) | 1.35*** | 1.35*** | 1.32*** | 1.30*** | 1.35*** |
| | (0.005) | (0.005) | (0.009) | (0.01) | (0.008) |
| GARCH(−2) | −0.35*** | −0.35*** | −0.32*** | −0.30*** | −0.36*** |
| | (0.006) | (0.005) | (0.009) | (0.01) | (0.008) |
| Adjusted $R^2$ | 0.80 | 0.80 | 0.82 | 0.78 | 0.80 |
| F stat. ARCH LM | 0.15 | 0.16 | 0.66 | 0.49 | 0.63 |
| N obs. | 49,281 | 49,281 | 15,898 | 16,432 | 16,951 |

Note: *; **; *** refer to 10%, 5% and 1% significance levels, respectively.

**APPENDIX 2: Sensitivity Analysis: Results of Regression including Time Dummies**

| Explanatory variables | 2006–2011, excl. cross-border measures | 2006–2011, incl. cross-border measures | 2006–2007 | 2008–2009 | 2010–2011 |
|---|---|---|---|---|---|
| constant | −0.66*** | −0.54*** | −1.18*** | −1.17*** | 0.33*** |
| | (0.02) | (0.02) | (0.04) | (0.03) | (0.03) |
| HHI (−1) | 1.28*** | 1.22*** | 1.06*** | 0.58*** | 0.94*** |
| | (0.04) | (0.04) | (0.11) | (0.06) | (0.04) |
| Demand(−1) | 0.03*** | 0.03*** | 0.08*** | 0.04*** | 0.007*** |
| | (0.0008) | (0.0008) | (0.002) | (0.002) | (0.001) |
| River temp | 0.04*** | 0.03*** | 0.06*** | 0.03 | 0.06*** |
| | (0.01) | (0.01) | (0.02) | (0.03) | (0.01) |
| Wind Ger | −0.008*** | −0.009*** | −0.01*** | −0.005*** | −0.005*** |
| | (0.0003) | (0.0003) | (0.0009) | (0.0006) | (0.0003) |
| EEX(−1) | 0.002*** | 0.002*** | 0.0006*** | 0.002*** | 0.005*** |
| | (0.00002) | (0.00002) | (0.00005) | (0.00004) | (0.00007) |
| Import capacity | | −0.04*** | | | |
| | | (0.003) | | | |
| D_MC_Be_Fr | | 0.02 | | | |
| | | (0.01) | | | |
| D_MC_Ger | | −0.04*** | | | |
| | | (0.01) | | | |
| D_h2 | −0.06*** | −0.06*** | −0.06*** | −0.08*** | −0.03*** |
| | (0.001) | (0.001) | (0.004) | (0.003) | (0.002) |
| D_h3 | −0.13*** | −0.13*** | −0.13*** | −0.16*** | −0.08*** |
| | (0.002) | (0.002) | (0.006) | (0.003) | (0.003) |
| D_h4 | −0.23*** | −0.23*** | −0.23*** | −0.27*** | −0.13*** |
| | (0.002) | (0.002) | (0.006) | (0.004) | (0.003) |
| D_h5 | −0.24*** | −0.24*** | −0.27*** | −0.31*** | −0.12*** |
| | (0.003) | (0.003) | (0.006) | (0.005) | (0.004) |
| D_h6 | −0.09*** | −0.09*** | −0.06*** | −0.13*** | −0.01** |
| | (0.003) | (0.003) | (0.006) | (0.005) | (0.004) |
| D_h7 | 0.05*** | 0.05*** | 0.06*** | 0.05*** | 0.09*** |
| | (0.001) | (0.001) | (0.006) | (0.005) | (0.004) |
| D_h8 | 0.18*** | 0.18*** | 0.27*** | 0.17*** | 0.19*** |
| | (0.003) | (0.003) | (0.006) | (0.005) | (0.004) |
| D_h9 | 0.17*** | 0.17*** | 0.22*** | 0.14*** | 0.18*** |
| | (0.003) | (0.003) | (0.007) | (0.005) | (0.005) |
| D_h10 | 0.19*** | 0.19*** | 0.23*** | 0.15*** | 0.18*** |
| | (0.003) | (0.003) | (0.007) | (0.006) | (0.006) |
| D_h11 | 0.19*** | 0.20*** | 0.25*** | 0.16*** | 0.18*** |
| | (0.004) | (0.004) | (0.009) | (0.007) | (0.006) |
| D_h12 | 0.22*** | 0.22*** | 0.30*** | 0.18*** | 0.19*** |
| | (0.004) | (0.004) | (0.01) | (0.008) | (0.006) |
| D_h13 | 0.19*** | 0.19*** | 0.22*** | 0.14*** | 0.17*** |
| | (0.005) | (0.005) | (0.01) | (0.008) | (0.006) |
| D_h14 | 0.16*** | 0.16*** | 0.21*** | 0.11*** | 0.14*** |
| | (0.004) | (0.004) | (0.01) | (0.008) | (0.005) |
| D_h15 | 0.13*** | 0.12*** | 0.16*** | 0.08*** | 0.11*** |
| | (0.004) | (0.004) | (0.01) | (0.008) | (0.006) |
| D_h16 | 0.08*** | 0.08*** | 0.12*** | 0.03*** | 0.08*** |
| | (0.004) | (0.004) | (0.01) | (0.008) | (0.006) |
| D_h17 | 0.08*** | 0.08*** | 0.11*** | 0.01* | 0.09*** |
| | (0.004) | (0.004) | (0.01) | (0.007) | (0.005) |
| D_h18 | 0.14*** | 0.15*** | 0.19*** | 0.07*** | 0.15*** |
| | (0.004) | (0.004) | (0.01) | (0.007) | (0.005) |

*(continued)*

**APPENDIX 2: Sensitivity Analysis: Results of Regression including Time Dummies** *(continued)*

| Explanatory variables | 2006–2011, excl. cross-border measures | 2006–2011, incl. cross-border measures | 2006–2007 | 2008–2009 | 2010–2011 |
|---|---|---|---|---|---|
| D_h19 | 0.20*** | 0.20*** | 0.22*** | 0.13*** | 0.19*** |
| | (0.004) | (0.004) | (0.01) | (0.006) | (0.004) |
| D_h20 | 0.19*** | 0.19*** | 0.20*** | 0.13*** | 0.17*** |
| | (0.003) | (0.003) | (0.007) | (0.006) | (0.004) |
| D_h21 | 0.16*** | 0.16*** | 0.19*** | 0.10*** | 0.14*** |
| | (0.003) | (0.003) | (0.006) | (0.006) | (0.004) |
| D_h22 | 0.09*** | 0.09*** | 0.12*** | 0.03*** | 0.08*** |
| | (0.003) | (0.003) | (0.006) | (0.005) | (0.003) |
| D_h23 | 0.10*** | 0.10*** | 0.13*** | 0.05*** | 0.11*** |
| | (0.002) | (0.002) | (0.005) | (0.004) | (0.002) |
| D_h24 | 0.05*** | 0.05*** | 0.05*** | 0.07*** | 0.02*** |
| | (0.001) | (0.001) | (0.004) | (0.003) | (0.002) |
| D_d2 | 0.002 | 0.002 | −0.03*** | 0.01*** | 0.001 |
| | (0.002) | (0.002) | (0.006) | (0.004) | (0.003) |
| D_d3 | 0.003 | 0.001 | −0.0003 | 0.01** | −0.003 |
| | (0.003) | (0.003) | (0.008) | (0.006) | (0.004) |
| D_d4 | 0.005 | 0.002 | −0.0009 | 0.01 | 0.005 |
| | (0.003) | (0.003) | (0.008) | (0.006) | (0.004) |
| D_d5 | 0.01*** | 0.008*** | 0.002 | 0.02*** | 0.01*** |
| | (0.003) | (0.003) | (0.008) | (0.006) | (0.004) |
| D_d6 | 0.007** | 0.005*** | 0.007 | 0.01 | 0.006* |
| | (0.003) | (0.003) | (0.007) | (0.005) | (0.003) |
| D_d7 | 0.02*** | 0.02*** | 0.07*** | 0.06*** | −0.009*** |
| | (0.002) | (0.002) | (0.005) | (0.003) | (0.002) |
| D_m2 | 0.06*** | 0.05*** | 0.07* | 0.07*** | 0.04*** |
| | (0.01) | (0.01) | (0.03) | (0.02) | (0.01) |
| D_m3 | 0.05*** | 0.05*** | 0.02 | 0.10*** | −0.01 |
| | (0.01) | (0.01) | (0.03) | (0.02) | (0.01) |
| D_m4 | 0.06*** | 0.06*** | 0.12*** | 0.07*** | 0.01 |
| | (0.01) | (0.01) | (0.03) | (0.02) | (0.01) |
| D_m5 | −0.004 | −0.006 | 0.03 | −0.004 | −0.02 |
| | (0.01) | (0.01) | (0.04) | (0.02) | (0.01) |
| D_m6 | 0.007 | 0.01 | 0.07* | 0.02 | −0.02** |
| | (0.01) | (0.01) | (0.04) | (0.02) | (0.01) |
| D_m7 | −0.0007 | 0.003 | −0.04 | 0.06*** | −0.04*** |
| | (0.01) | (0.01) | (0.04) | (0.02) | (0.01) |
| D_m8 | 0.04*** | 0.04*** | −0.03 | 0.08*** | −0.003 |
| | (0.01) | (0.01) | (0.04) | (0.02) | (0.01) |
| D_m9 | 0.05*** | 0.05*** | 0.01 | 0.10*** | 0.001 |
| | (0.01) | (0.01) | (0.04) | (0.02) | (0.01 |
| D_m10 | 0.07*** | 0.07*** | 0.09*** | 0.17*** | −0.02** |
| | (0.01) | (0.01) | (0.04) | (0.02) | (0.01) |
| D_m11 | 0.03*** | 0.04*** | 0.08** | 0.07*** | −0.03** |
| | (0.01) | (0.01) | (0.04) | (0.02) | (0.01) |
| D_m12 | −0.003 | 0.005 | 0.02 | 0.01 | −0.05*** |
| | (0.01) | (0.01) | (0.03) | (0.02) | (0.01) |
| Trend | 0.0000009 | 0.000001 | 0.000004 | 0.00002 | 0.000006 |
| | (0.0000002)*** | (0.0000004)*** | (0.000002)* | (0.000001)* | (0.0000007)*** |
| AR(1) | 0.75*** | 0.75*** | 0.75*** | 0.74*** | 0.72*** |
| | (0.002) | (0.002) | (0.004) | (0.004) | (0.004) |
| AR(24) | 0.13*** | 0.13*** | 0.13*** | 0.10*** | 0.13*** |
| | (0.002) | (0.002) | (0.004) | (0.004) | (0.004) |

*(continued)*

**APPENDIX 2: Sensitivity Analysis: Results of Regression including Time Dummies** *(continued)*

| Explanatory variables | 2006–2011, excl. cross-border measures | 2006–2011, incl. cross-border measures | 2006–2007 | 2008–2009 | 2010–2011 |
|---|---|---|---|---|---|
| *Variance equation* | | | | | |
| Res. $(-1)^2$ | 0.31*** | 0.31*** | 0.25*** | 0.37*** | 0.36*** |
| | (0.003) | (0.003) | (0.005) | (0.005) | (0.005) |
| Res. $(-2)^2$ | −0.31*** | −0.31*** | −0.25*** | −0.37*** | −0.35*** |
| | (0.003) | (0.003) | (0.005) | (0.005) | (0.005) |
| GARCH(−1) | 1.40*** | 1.40*** | 1.51*** | 1.33*** | 1.37*** |
| | (0.006) | (0.006) | (0.01) | (0.01) | (0.009) |
| GARCH(−2) | −0.40*** | −0.40*** | −0.51*** | −0.33*** | −0.37*** |
| | (0.006) | (0.006) | (0.01) | (0.01) | (0.009) |
| Adjusted $R^2$ | 0.83 | 0.83 | 0.85 | 0.83 | 0.83 |
| F stat. ARCH LM | 0.53 | 0.53 | 0.66 | 0.49 | 0.76 |
| N obs. | 49,281 | 49,281 | 15,898 | 16,432 | 16,951 |

Note: *; **; *** refer to 10%, 5% and 1% significance levels, respectively.